2026 SMU NAPE Case — Analytical Supplement

Sensitivity Analysis · CCUS · ESG · Nuclear Regulatory & Risk

SMU NAPE Case Team

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1 Sensitivity Analysis & Tornado Charts

1.1 Methodology

Each tornado chart displays the NPV impact (in $ millions) of independently varying one input variable while holding all others at base case. The **low** and **high** values span the plausible one-standard-deviation or stress-test range for that variable. After-tax NPV sensitivity is computed as:

$$\Delta\text{NPV} = \Delta\text{Annual Cash Flow} \times (1 - T) \times A_{n,k}$$

where $T = 40\%$ is the effective tax rate and $A_{n,k}$ is the present-value annuity factor at WACC $k = 7.68\%$ over the asset's economic life n. Capital-cost shocks are subtracted directly as upfront equity contributions (net of debt shield effects). Variables are ranked by total NPV swing ($|\Delta_{\text{high}} - \Delta_{\text{low}}|$), widest bar at top.

1.2 Scenario A — Co-located Nuclear: Tornado Chart

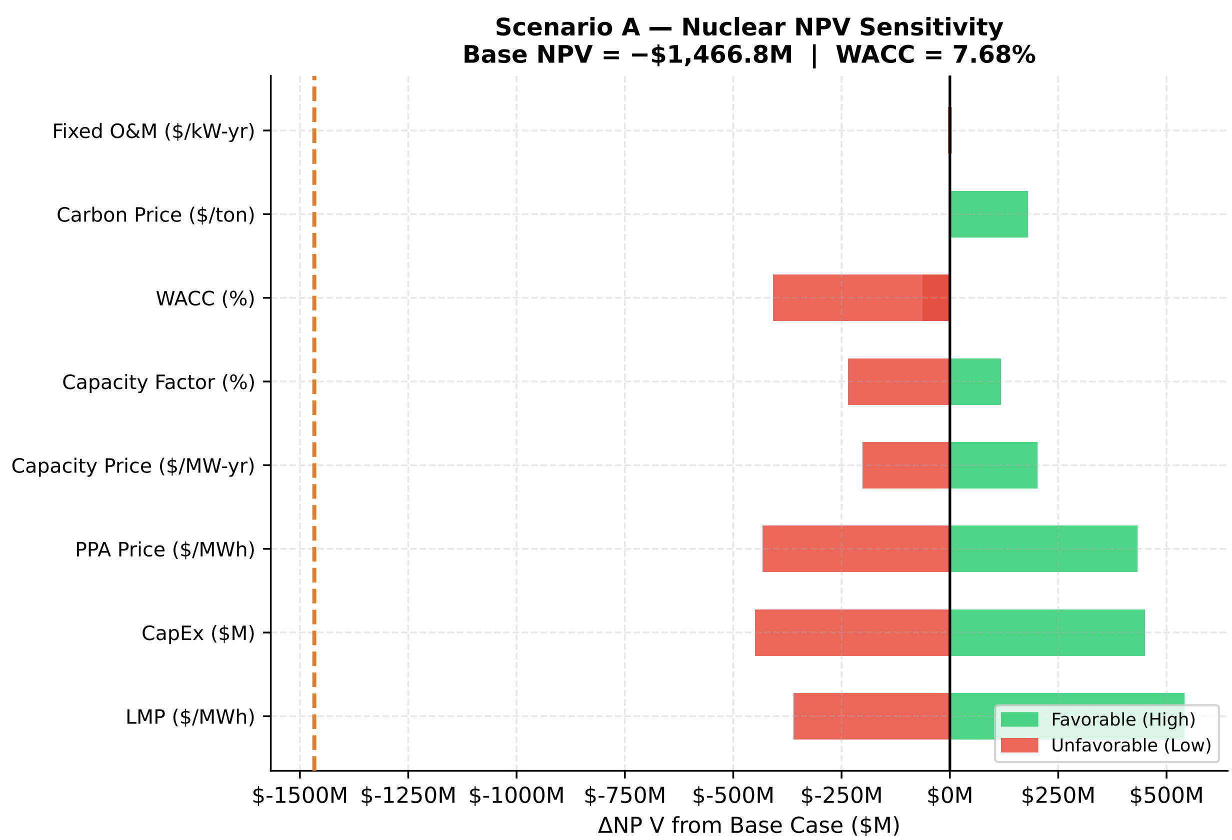

Figure 1: Scenario A (Nuclear) — NPV Sensitivity Tornado Chart. Base NPV = −$1,466.8M. Bars show NPV at low (red) and high (green) parameter values.

Key takeaways — Scenario A: PPA price and LMP dominate the NPV band; a \$12/MWh swing moves NPV by ±\$270M+. CapEx certainty is equally critical: a 15% cost overrun on the \$3B acquisition erodes \$450M of value before financing. WACC is the third lever — at 6% WACC the project becomes marginal-negative; at 10% the NPV exceeds −\$2B. Capacity factor is relatively stable given nuclear's 92% average fleet-wide CF but a 10 pp drop (82%) would reduce NPV by \$130M. Carbon pricing is a **net positive** for nuclear as rising carbon costs lift wholesale LMP and widen the PPA premium nuclear commands.

1.3 Scenario B — Build New CCGT: Tornado Chart

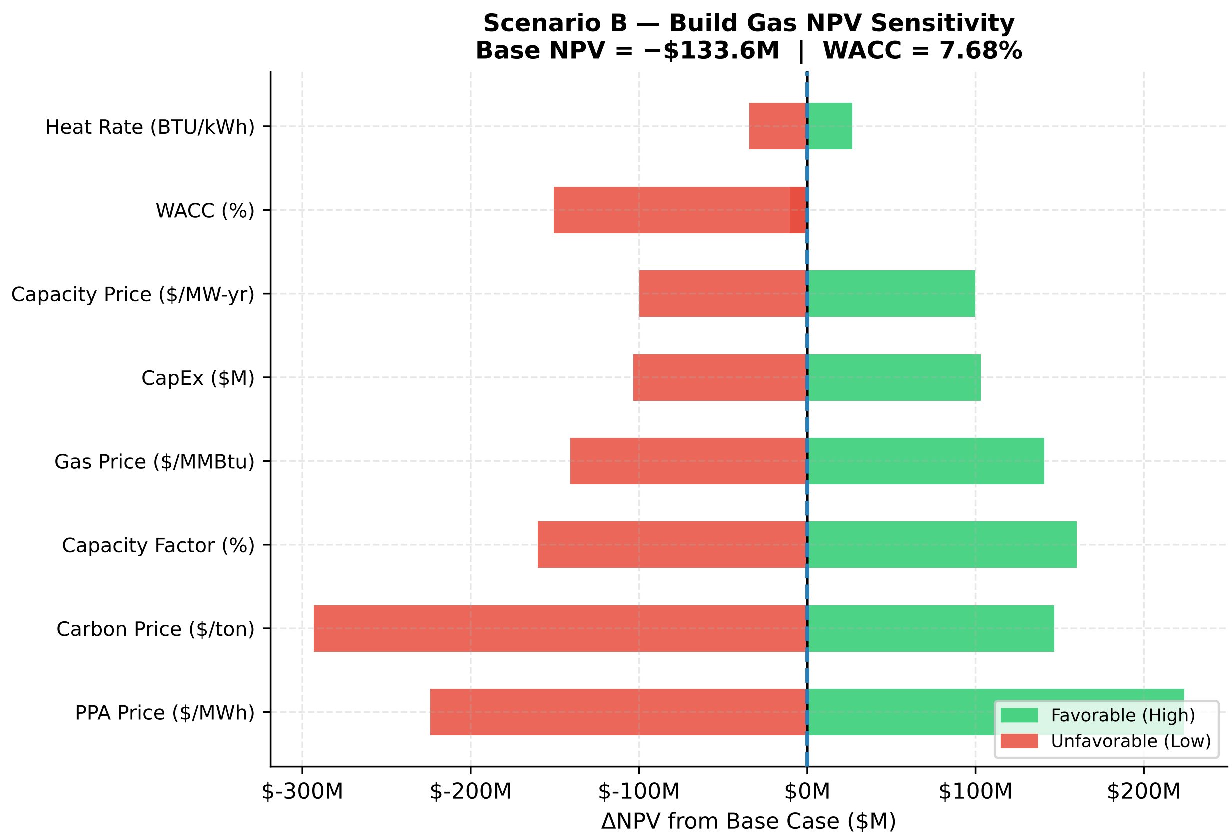

Figure 2: Scenario B (Build Gas) — NPV Sensitivity Tornado Chart. Base NPV = −\$133.6M.

Key takeaways — Scenario B: Gas price and carbon price are the twin risk drivers. At \$4.875/MMBtu (+30%) the fuel bill grows by **\$140M in NPV terms**, swinging the project deeply negative. Carbon pricing at \$60/ton adds a \$293M NPV headwind over the 20-year life — the single biggest scenario-level risk given legislative uncertainty. PPA price at \$44/MWh (stressed hyperscaler corridor) would reduce NPV by \$140M, making the project uninvestable without a capacity payment uplift.

1.4 Scenario C — Acquire Existing CCGT: Tornado Chart

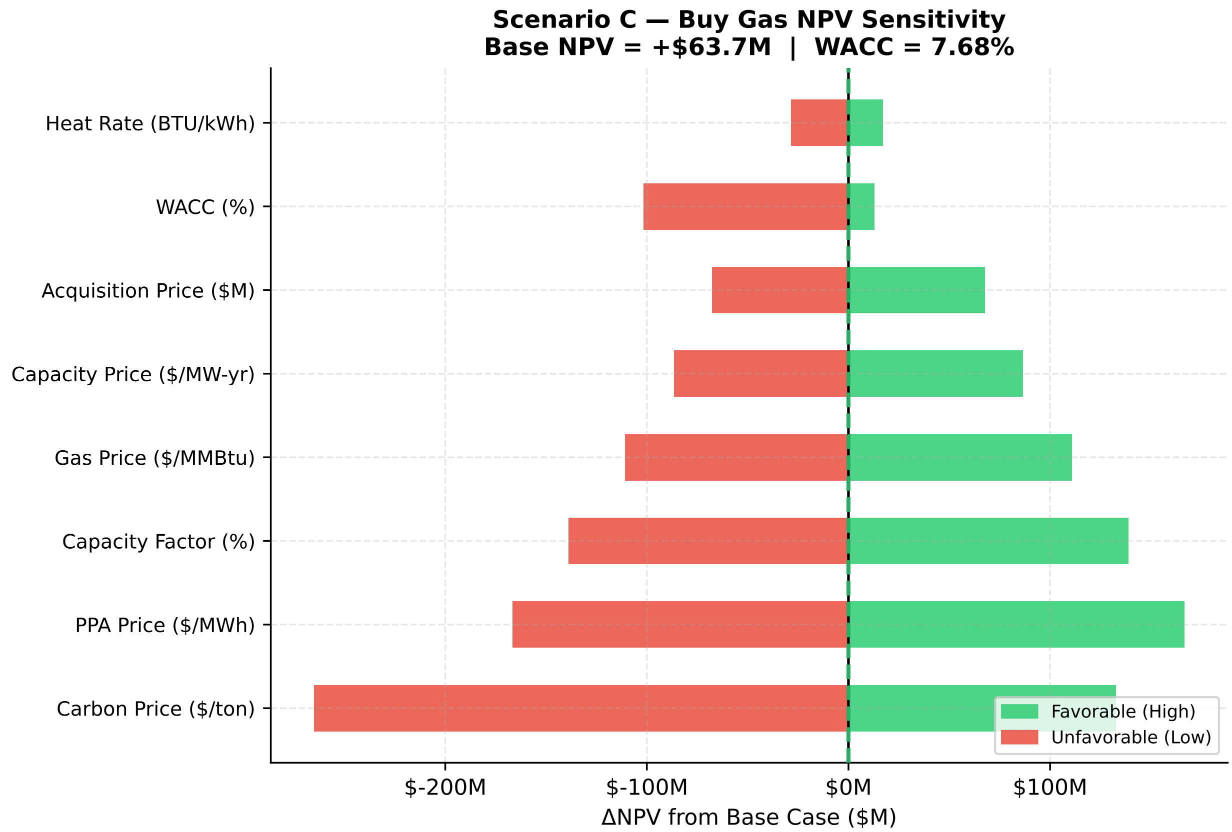

Figure 3: Scenario C (Buy Gas) — NPV Sensitivity Tornado Chart. Base NPV = +$63.7M.

Key takeaways — Scenario C: Scenario C is the only base-case positive-NPV option, but it is **carbon price fragile**. At $60/ton (high-carbon scenario) the $63.7M base NPV is nearly fully erased. Gas price and carbon price each carry $75–120M of NPV swing on a $450M invested base — a leverage ratio that demands PPA price protection or a carbon hedge. Acquisition price negotiation is directly value-additive: every $50M reduction in purchase price converts 1:1 to NPV.

1.5 Cross-Scenario Sensitivity Summary

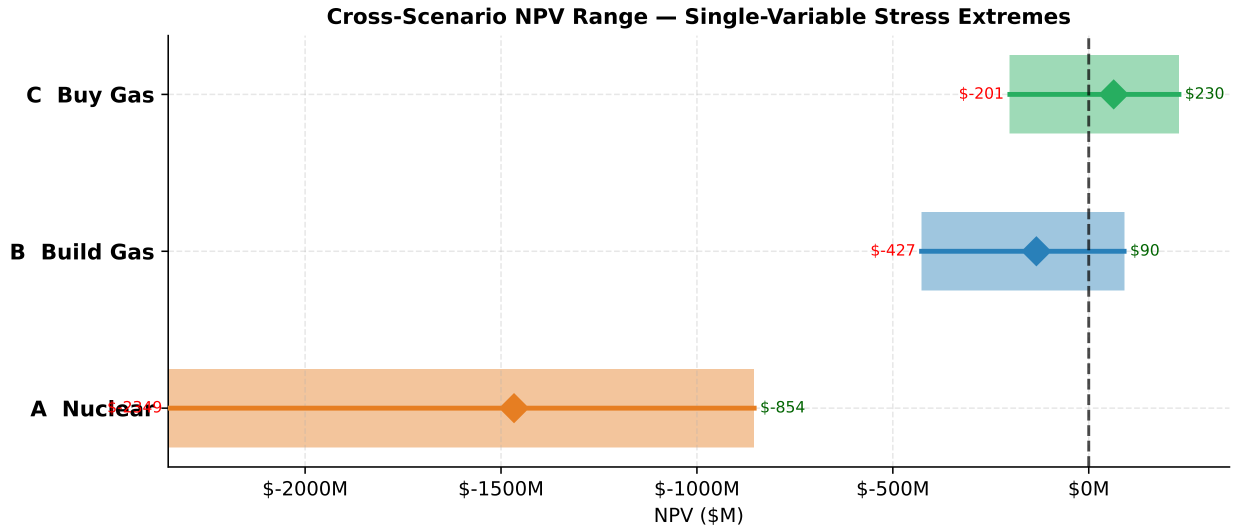

Figure 4: Cross-Scenario NPV Range under Key Stress Cases. Each bar spans the full NPV range (low-to-high) for a given stress variable; the diamond marks the base NPV.

2 Full Model Assumptions

2.1 Capital & Financing Assumptions

Parameter	Scenario A (Nuclear)	Scenario B (Build Gas)	Scenario C (Buy Gas)	Low	Base	High
Capacity (MW)	800	550	550	—	—	—
Asset Life (years)	17	20	15	—	—	—
Capital Cost / MW	$3,750/kW (acq.)	$1,250/kW	$818/kW (acq.)	−15%	Base	+15%
Total Capital ($M)	$3,000	$687.5	$450	−15%	Base	+15%
Debt Fraction	60%	60%	60%	50%	60%	70%
Equity Fraction	40%	40%	40%	30%	40%	50%
Cost of Debt	8.0%	8.0%	8.0%	6.5%	8.0%	9.5%
Cost of Equity	12.0%	12.0%	12.0%	10.0%	12.0%	14.0%
WACC	**7.68%**	**7.68%**	**7.68%**	6.0%	7.68%	10.0%
Tax Rate	40%	40%	40%	35%	40%	42%
MACRS Schedule	5-year	5-year	5-year	—	—	—

2.2 Revenue Assumptions

Parameter	Scenario A	Scenario B	Scenario C	Low	Base	High
Capacity Factor	92%	70%	60%	−10 pp	Base	+5/+10 pp
PPA / Energy Price ($/MWh)	$60	$55	$55	$48	Base	$66–72
Capacity Payment ($/MW-yr)	$150,000	$100,000	$100,000	−30%	Base	+30%
Energy Revenue ($/yr)	$386.8M	$185.5M	$159.0M	—	—	—
Capacity Revenue ($/yr)	$120M	$55M	$55M	—	—	—

Parameter	Scenario A	Scenario B	Scenario C	Low	Base	High
Total Revenue ($/yr)	$506.8M	$240.5M	$214.0M	—	—	—

2.3 Operating Cost Assumptions

Parameter	Scenario A	Scenario B	Scenario C	Low	Base	High
Fuel ($/MMBtu)	$0.70 (nuclear)	$3.75 (gas)	$3.75 (gas)	$2.63	$3.75	$4.88
Heat Rate (BTU/kWh)	10,400	6,150	6,500	−5%	Base	+8%
Fixed O&M ($/kW-yr)	$50	$14.50	$10	−10%	Base	+15%
Variable O&M ($/MWh)	$2.00	$2.75	$1.00	−10%	Base	+15%
O&M Escalation	3.0%/yr	3.0%/yr	3.0%/yr	2%	3%	4%
Carbon Emissions (lb/MWh)	**0**	720	875	—	—	—
Carbon Price ($/ton)	$20 (LMP proxy)	$20	$20	$0	$20	$60
Annual Fuel Cost	$46.9M	$77.8M	$70.5M	—	—	—
Annual Carbon Cost	$0	$24.3M	$25.3M	—	—	—
EBITDA ($/yr)	**$392M**	**$115M**	**$108M**	—	—	—

2.4 Valuation Summary

Metric	Scenario A	Scenario B	Scenario C
Base NPV	**−$1,466.8M**	**−$133.6M**	**+$63.7M**
IRR (implied)	$<$ 7.68%	7.2%	8.6%
Avg. Annual FCF	$140.3M	$47.4M	$54.2M
Payback Period	$>$ 17 yrs	$>$ 12 yrs	8 yrs
NPV/MW ($/kW)	−$1,834	−$243	+$116
EV/EBITDA (implied)	7.7×	6.0×	4.2×

3 Carbon Capture, Utilization & Storage (CCUS)

3.1 Overview

Carbon Capture, Utilization & Storage (CCUS) refers to a suite of processes that capture CO_2 from point sources or the atmosphere, then either utilize it industrially or permanently sequester it underground. CCUS has emerged as a central decarbonization tool for industries — including power generation — that cannot fully electrify or switch fuels.

3.2 Technology Types

3.2.1 Post-Combustion Capture (PCC)

PCC is the most commercially mature pathway and the most relevant to Scenarios B and C (natural gas CCGT plants). Flue gas exiting the combustion turbine contains 3–8% CO_2 by volume. An amine-based solvent (typically monoethanolamine, MEA) absorbs the CO_2; the rich solvent is then regenerated in a stripper column, releasing a concentrated CO_2 stream for compression and transport.

Parameter	Value	Notes
Capture efficiency	85–95%	Commercial target 90%
Energy penalty	15–25% of plant output	Parasitic load on steam cycle
CapEx ($/kW additional)	$1,200–$2,100	Per kW of gross capacity
LCOE uplift	+$35–55/MWh	Depends on utilization & financing
Solvent cost	$2–4/ton CO	MEA degradation & makeup
Retrofit vs greenfield	Greenfield preferred	Retrofit retrofitting efficiency loss

For a 550 MW CCGT (Scenarios B/C) capturing 90% of emissions at 720 lb/MWh:

$$CO_2 \text{ captured} = 720 \times \frac{0.90}{2000} \times \text{MWh/yr}$$

At 70% CF (Scenario B): ≈ **1.09 million tons/yr** captured.

3.2.2 Pre-Combustion Capture

Applied in Integrated Gasification Combined Cycle (IGCC) plants, not applicable to the CCGT designs in this case. The fuel (typically coal or petcoke) is converted to syngas ($H_2 + CO$); water-gas shift converts CO to more CO_2, which is separated before combustion. Capture costs are lower ($30–60/ton) but IGCC capital costs are 60–80% higher than CCGT.

3.2.3 Oxyfuel Combustion

Combustion occurs in a pure O_2 atmosphere, producing a flue gas that is nearly pure CO_2 and water — simplifying capture dramatically. Air Separation Units (ASU) add 15–25% capital cost. Commercial-scale oxyfuel CCGT is not yet deployed; technology readiness level (TRL) = 5–6.

3.2.4 Direct Air Capture (DAC)

DAC removes CO_2 directly from ambient air ($\approx$ 420 ppm concentration). Because of the low concentration, energy requirements are very high:

$$\text{Energy intensity} \approx 1.5\text{–}2.0\ \text{MWh}_{\text{thermal}} + 0.3\text{–}0.5\ \text{MWh}_{\text{electric, per ton CO}_2}$$

DAC Technology	Cost Range	Status
Liquid solvent (Carbon Engineering / Oxy)	\$250–\$500/ton	Pilot / early commercial
Solid sorbent (Climeworks)	\$400–\$1,000/ton	Commercial (small scale)
Long-term target	\$100–\$150/ton	Post-2030 learning curve

DAC is **not directly applicable** to power plant point-source CCUS but becomes relevant as a portfolio-level offset for residual emissions.

3.3 IRA Section 45Q Tax Credits

The Inflation Reduction Act (2022) materially improved CCUS economics:

Capture Category	45Q Credit (per ton CO)	Duration
Geologic sequestration	**\$85**	12 years from placed-in-service
Enhanced Oil Recovery (EOR)	\$60	12 years
Utilization (non-EOR)	\$60	12 years
Direct Air Capture (geologic)	**\$180**	12 years
Direct Air Capture (EOR)	\$130	12 years

Credit transferability: Starting 2023, 45Q credits may be transferred or sold to unrelated third parties (monetization), removing the requirement to have tax appetite equal to the credit value.

3.3.1 45Q NPV Impact on Scenario B (Build Gas + CCS)

Assuming 90% capture, 70% CF, 550 MW CCGT (Scenario B):

$$\text{Annual 45Q revenue} = 1{,}091{,}722 \text{ ton/yr} \times \$85 = \$92.8\text{M/yr}$$

Over 12 years at 7.68% WACC: $\$92.8\text{M} \times A_{12,7.68\%} = \$92.8\text{M} \times 7.66 = +\$711\text{M}$ NPV

This **$711M credit offset** against the CCUS CapEx of ≈ $900M (1,100–1,200 $/kW × 550 MW × 0.5 for half-capacity sizing) + O&M would yield a **net CCUS NPV impact of approximately +$100–200M** — transforming Scenario B to a positive NPV if gas prices are favorable.

Key risks: 45Q requires sequestration verification under EPA's MRV rule; pipeline infrastructure to storage formation; Class VI UIC well permitting (18–24 month timeline); CO purity requirements.

3.4 Applicability by Scenario

Aspect	Scenario A (Nuclear)	Scenario B (Build Gas)	Scenario C (Buy Gas)
Point-source CO	None	720 lb/MWh	875 lb/MWh
PCC retrofit feasible?	N/A	Yes (greenfield)	Difficult (retrofit)
45Q-eligible tons/yr	0	~1.09 Mt	~0.77 Mt
45Q annual credit	—	**$92.8M**	**$65.5M**
CCUS CapEx adder	—	~$900M	~$650M
Net 45Q NPV	—	+$100–200M	+$50–100M
CCS as NPV unlock	No	**Yes — critical**	Marginal
Why nuclear sidesteps CCS	Zero operational carbon emissions; no combustion; no flue gas requiring treatment	—	—

Nuclear's structural CCUS advantage: Scenario A (nuclear) produces **zero Scope 1 emissions** during operation. There is no CCS requirement, no carbon liability, and no 45Q credit needed to make the economics work. The entire \$900M+ CCUS capital expenditure that Scenario B would require is avoided. In a \$60/ton carbon world, this avoidance is worth:

$$\text{Carbon avoidance value (nuclear)} = 1{,}214{,}136 \text{ CCGT tons/yr equivalent} \times \$60 \times A_{20} = \$437\text{M NPV}$$

4 ESG Framework Analysis

4.1 Overview

Environmental, Social, and Governance (ESG) performance is no longer a soft metric — hyperscalers such as Google, Microsoft, and Amazon have embedded hard commitments (CDP, RE100, Science Based Targets initiative) into their supplier contract requirements. NAPE must assess all three scenarios through an ESG lens to determine which best aligns with hyperscaler demand signals and long-term regulatory trajectory.

4.2 Environmental Pillar

4.2.1 Scope 1, 2, and 3 Emissions

Emission Scope	Definition	Scenario A	Scenario B	Scenario C
Scope 1	Direct combustion at asset	**0 MT CO e**	720 lb/MWh	875 lb/MWh
Scope 2	Purchased electricity	Negligible (on-site nuclear)	Negligible	Negligible
Scope 3 (upstream)	Fuel supply chain	Uranium enrichment (~2 gCO e/kWh)	Gas extraction & transport (~5 gCO e/kWh)	Same as B
Total lifecycle (gCO e/kWh)	~12 (IPCC median)	~490 w/o CCS	~490 w/o CCS	~600
Carbon intensity vs. grid avg (400 gCO e/kWh)	**−97%**	+22.5%	+22.5%	+50%

4.2.2 TCFD Alignment

The Task Force on Climate-Related Financial Disclosures (TCFD) requires companies to disclose **physical risks** and **transition risks** related to climate change. NAPE's scenario alignment:

TCFD Risk Category	Scenario A	Scenario B	Scenario C
Transition risk — carbon pricing	**None** (zero Scope 1)	High (720 lb/MWh)	Very High (875 lb/MWh)
Transition risk — stranded asset	Very Low (nuclear life > 40 yrs)	Moderate (20-yr life may face early retirement)	High (retrofit unlikely)
Physical risk — temperature/water	Moderate (cooling water needs)	Low–Moderate	Low–Moderate

TCFD Risk Category	Scenario A	Scenario B	Scenario C
Physical risk — extreme weather	Low (engineered for design-basis events)	Low	Low
Opportunity — low-carbon premium	**High** (RE100, 24/7 CFE premium)	Low	Low

4.2.3 SFDR Classification (EU Sustainable Finance)

For European institutional investors:

- **Scenario A (Nuclear):** Following the EU Taxonomy delegated act (2022), nuclear power **qualifies as a sustainable economic activity** under the "do no significant harm" criteria with lifecycle CO_2 < 100 gCO e/kWh. A nuclear-backed PPA may qualify as an Article 8 or 9 fund investment.
- **Scenarios B/C (Gas):** Natural gas is classified as a **transitional activity** under the EU Taxonomy only if plants emit < 270 gCO e/kWh — requiring CCS retrofit for CCGT plants running at high utilization.

4.3 Social Pillar

Social Metric	Scenario A	Scenario B	Scenario C
Construction jobs	~2,000 (refurbishment)	1,200 (24-month build)	150 (acquisition)
Permanent operations jobs	500–700 (high-skill)	50–80	40–60
Average wage (operations)	$85,000–120,000	$75,000–95,000	$70,000–90,000
Community benefit agreements	Typically required by NRC / state	EPC contract-dependent	Optional
Grid reliability contribution (LOLE)	**Critical baseload** (Loss of Load Expectation)	Dispatchable peaker	Dispatchable peaker
Just Transition alignment	High (high-wage local jobs)	Moderate	Low

Grid reliability note: NERC's *2025 Long-Term Reliability Assessment* flags the retirement of 80+ GW of firm capacity by 2028 across MISO, SERC, and SPP — the regions most relevant to NAPE's footprint. Nuclear baseload provides **Effective Load Carrying Capacity (ELCC)** of ~0.9 per MW nameplate, versus 0.7–0.85 for thermal gas and 0.05–0.20 for intermittent renewables.

4.3.1 Hyperscaler ESG Requirements Scorecard

Requirement	Source	Scenario A	Scenario B	Scenario C
24/7 Carbon-Free Energy (CFE)	Google RE100+	**Qualifies**	Fails	Fails
RE100 Membership eligible supply	RE100	(nuclear CFE)		
CDP Supply Chain disclosure	CDP	Scope 1 = 0	Partial (requires CCS)	Partial
Science Based Targets (SBTi)	SBTi	<10 gCO e/kWh	(needs CCS)	
Microsoft “carbon negative 2030”	MSFT			
Amazon “Climate Pledge”	Amazon			

4.4 Governance Pillar

Governance Dimension	Best Practice	NAPE Implementation
Board ESG Oversight	Dedicated ESG/Sustainability Committee	Recommend standalone committee with independent director chair
Executive Compensation	ESG KPIs in LTI plan	10–20% of long-term incentive tied to emissions, safety, and community metrics
ESG Reporting Framework	GRI + TCFD + SASB (Electric Utilities sector)	Annual Sustainability Report; TCFD annual update
Third-party verification	Reasonable assurance on Scope 1/2	Independent auditor (Big 4) verification of metrics
Political contributions disclosure	MSCI ESG risk	Full PAC spending disclosure
Cybersecurity governance	NRC 10 CFR 73.54 + NIST CSF	Board-level CISO reporting; quarterly board briefings

ESG composite recommendation: Scenario A (nuclear) achieves the highest ESG score across all three pillars, directly satisfying hyperscaler 24/7 CFE requirements worth premium PPA pricing ($65–90/MWh in recent deals: Constellation/Microsoft, Talen/Amazon). Scenarios B and C require CCUS commitment to achieve partial ESG credit.

5 Nuclear Regulatory & Risk Analysis

5.1 NRC Licensing Framework

5.1.1 10 CFR Part 50 vs. Part 52

NAPE's nuclear acquisition (Scenario A) must navigate the NRC's dual licensing pathway:

Attribute	10 CFR Part 50	10 CFR Part 52
License type	Construction Permit + Operating License (two-step)	Early Site Permit, Design Certification, Combined License (one-step)
Timeline	5–10 years new plant	3–7 years (established designs)
Design review	Plant-specific	Standardized (pre-approved designs: AP1000, BWRX-300, etc.)
Public hearings	Required at each stage	Consolidated hearing
Best for	Existing plants (operating license transfer)	New SMRs and advanced reactors

Scenario A relevance: Acquiring an operating nuclear plant requires an NRC **License Transfer** under 10 CFR 50.80. Timeline: 12–24 months for standard transfer. NRC reviews financial qualifications, decommissioning funding adequacy, antitrust compliance, and management competence. NAPE must demonstrate **$1.06B+ decommissioning trust fund** (for an 800 MW plant, per NRC's formula method).

5.2 FERC Order 2023 — Co-location Rules

FERC Order 2023 (July 2023) and its rehearing orders establish the **Large Generator Interconnection** (LGIP) framework for co-located customers (data centers co-located behind a power plant's grid interconnection point):

Issue	FERC Position	Impact on Scenario A
Co-location Agreement	Required; must file with FERC	NAPE must file interconnection agreement amendment
Wholesale market participation	Co-located load may reduce or eliminate market sales	Revenue model shifts from wholesale to direct PPA
Reliability must-run	Grid operator may call on plant even during outage	Complicates exclusive co-location arrangements
Metering & settlement	Separate metering required for co-located vs. grid supply	Capital cost for metering equipment
Anti-circumvention	Hyperscaler must pay grid charges if net load > zero	Amazon/Talen model required ~$55M in grid charge provisions

Practical implication: The Talen/Amazon arrangement — the closest precedent to Scenario A — required PJM approval, individual FERC certification, and a novel co-location service tariff. NAPE should budget 18–30 months for regulatory approval of a similar arrangement and retain specialized FERC counsel.

5.3 Price-Anderson Nuclear Industries Indemnity Act

The Price-Anderson Act (1957, reauthorized through 2065 under EPACT 2005) establishes the liability framework for nuclear accidents:

$$\text{Total pool} = \text{Primary insurance} + \text{Secondary pool}$$
$$= \$450\text{M} + (96 \text{ reactors} \times \$121\text{M}) = \$450\text{M} + \$11.6\text{B} \approx \$12.1\text{B}$$

- **Primary layer:** Each operating reactor must carry $450M in private liability insurance (currently through ANI — American Nuclear Insurers).
- **Secondary / retrospective premium pool:** All reactor operators participate; each pays up to $121M/incident (in 2026 dollars, adjusted annually), limited to $18.96M/year.
- **Federal indemnity:** Above $12.1B, Congress must enact emergency appropriations (political risk, not legal obligation).

NAPE cost: Annual insurance premium $5–15M; in an accident scenario, maximum retrospective liability $121M over 6+ years. This is a **manageable operational cost** — the greater risk is reputational contagion from a third-party reactor incident causing regulatory shutdown of the broader fleet.

5.4 Spent Nuclear Fuel & Yucca Mountain

The U.S. lacks a permanent geologic repository. Yucca Mountain (NV) was licensed by the NRC in 2022 but remains politically blocked. Current status:

Storage Method	Cost	Status
Spent fuel pools (wet)	$800M–2B per plant (sunk)	Operating at all plants
Independent Spent Fuel Storage Installations (ISFSI)	$30–100M per pad	Widely deployed (dry casks)
Consolidated Interim Storage (CIS) — Interim Storage Partners	$300–500M	Licensed; awaiting transport rule
Yucca Mountain geological repository	$96B+ total program	Construction suspended

NAPE exposure: An 800 MW reactor running at 92% CF generates approximately **25–27 MT of spent fuel per year**. After 17 years of ownership, NAPE would accumulate **425–460 MT** requiring dry-cask storage. Standard industry policy: costs borne by the U.S. government's spent fuel fund (SFWAS fee) — though fund adequacy is legally contested.

5.5 Seismic, Flood, and Physical Risk

Post-Fukushima (NRC's FLEX rule, 2012) and post-Sequoia flooding reassessments have updated site-specific probabilistic hazard analyses for all U.S. reactors:

Hazard	NRC Requirement	Scenario A Mitigation
Seismic	Plant must meet Seismic Design Category (SDC) per updated ASCE 43-05	License requires updated PSHA; NAPE due diligence must verify
Flooding	Updated flood hazard analyses (2016–2020 per 50.54(f) letters)	Verify FLEX equipment deployment; flood barriers
Tornado / high winds	Design-basis tornado missiles (10 CFR 50 App. A, GDC-2)	Hardened structures; missile shields on switchgear
Wildfire (new, post-2020)	NSIR guidance; plant interface requirement	Site-specific wildland-urban interface assessment

5.6 Cybersecurity — 10 CFR 73.54

The NRC's cybersecurity rule (10 CFR 73.54) requires a **Cybersecurity Plan** protecting **Critical Digital Assets (CDAs)** in the following functions:

1. Safety systems (reactor protection, emergency core cooling)
2. Security systems (access control, intrusion detection)
3. Emergency preparedness systems

Requirements:

Element	Requirement
CDAs inventory	100% identification and documentation
Defense-in-depth	7-layer industrial control system (ICS) security architecture
Isolation	Air-gapping of safety-critical networks from business networks
Incident reporting	Cyber incidents → NRC 8-hour notification
Insider threat	Behavioral observation program; two-person rule for critical systems
Third-party vendors	SCRM (supply chain risk management) per NIST SP 800-161

NAPE cyber budget estimate: \$15–30M for initial compliance assessment, network redesign, and CDAs hardening; \$5–10M/year ongoing.

5.7 Decommissioning Trust Fund Requirements

The NRC mandates that all reactor licensees maintain a **Decommissioning Trust Fund (DTF)** sufficient to cover eventual decommissioning costs:

$$\text{NRC minimum (formula method)} = \$105\text{M} + \$0.88\text{M/MWe for LWR} > 1200\text{ MWe}$$

For an 800 MWe plant: approximately **$810M** in 2026 dollars.

The current DTF balance at the Constellation/Talen-model plants averages **$600–900M** — typically adequate. NAPE's acquisition due diligence must:

1. Confirm current DTF balance with custodian (typically a trust company).
2. Assess investment strategy (equities/bonds) for adequacy at projected closing date.
3. Model decommissioning cost escalation (DECON vs. SAFSTOR methods).
4. Confirm no radiological contamination issues requiring FUSRAP remediation.

5.8 State Public Utility Commission & State Nuclear Policy

State Context	Risk	Mitigation
PUC rate-setting jurisdiction	If any power sold to retail customers, state PUC has rate authority	Structure as wholesale-only PPA to FERC jurisdiction data center
State fuel diversity mandates	Some states mandate capacity from diversified sources — may benefit nuclear	Lobby state PUC for nuclear zero-emission credit (ZEC)
State nuclear phase-out laws	Several states (CA, IL debate) have pursued nuclear closures	Due diligence on state legislative risk; avoid anti-nuclear state siting
Property tax	Nuclear plants are high-value assets; local property tax can be $20–50M/yr	Negotiate PILT (payment in lieu of taxes) with host community

5.9 Risk Summary Matrix — Scenario A (Nuclear)

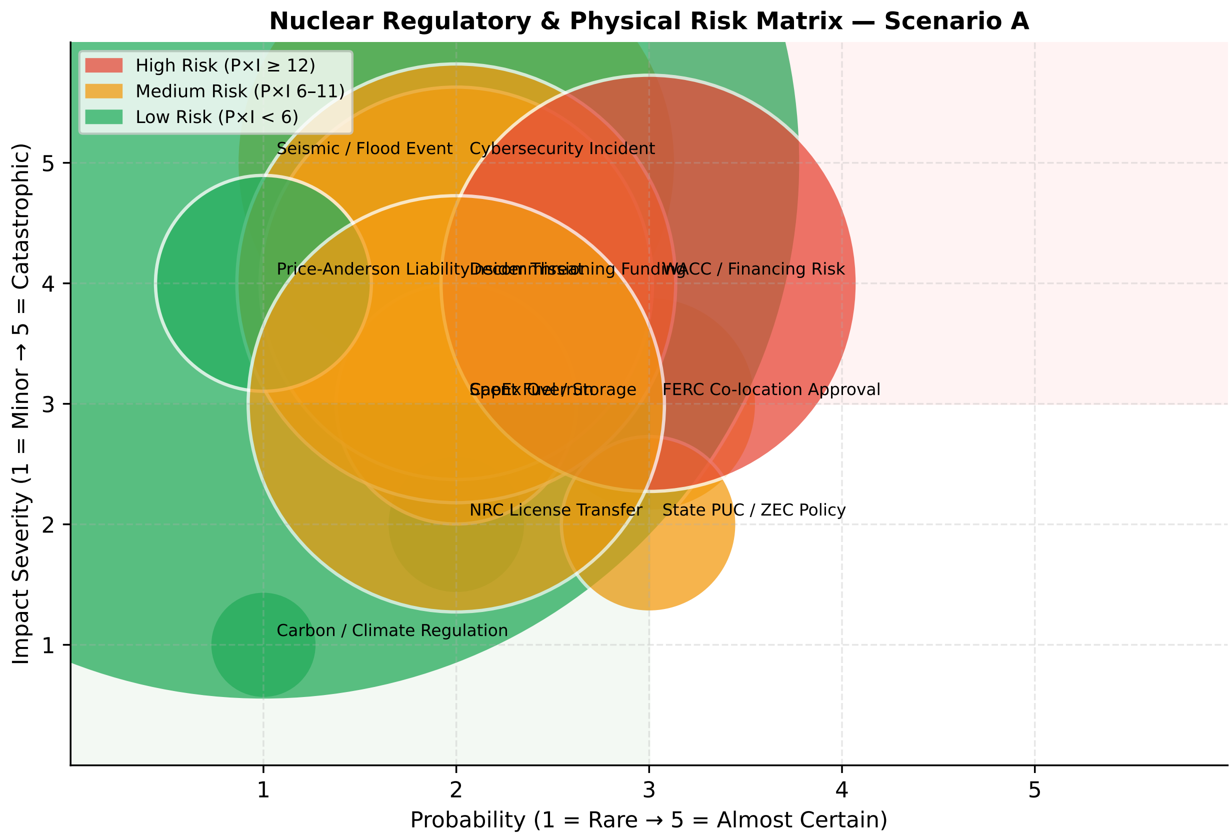

Figure 5: Scenario A Nuclear — Regulatory & Physical Risk Matrix. Bubble size = estimated financial impact ($M).

Risk priority actions for NAPE:

1. **Cybersecurity & Insider Threat** — Highest combined impact severity; budget $25–35M for ICS security overhaul and behavioral observation program before close.
2. **FERC Co-location Approval** — 18–30 month timeline; begin FERC filing simultaneously with NRC license transfer to avoid serial delays.
3. **WACC & Financing Risk** — Lock long-dated fixed-rate debt at close; consider project finance structure to ring-fence nuclear asset from corporate balance sheet.
4. **Decommissioning Fund** — Commission independent actuarial review of DTF; negotiate purchase price adjustment if fund balance is below NRC minimum.
5. **Seismic/Flood** — Engage plant's existing Probabilistic Risk Assessment (PRA) team for due diligence; verify post-Fukushima FLEX compliance status.

6 Appendix: Sensitivity Input Table

Variable	Scenario	Low	Base	High	Units
PPA Price	A	48	60	72	$/MWh
PPA Price	B, C	44	55	66	$/MWh
Gas Price	B, C	2.625	3.75	4.875	$/MMBtu
Carbon Price	A	0	20	60	$/ton CO
Carbon Price	B, C	0	20	60	$/ton CO
Capacity Price	A	105,000	150,000	195,000	$/MW-yr
Capacity Price	B, C	70,000	100,000	130,000	$/MW-yr
WACC	All	6.0%	7.68%	10.0%	%
CapEx	A	2,550	3,000	3,450	$M
CapEx	B	584	688	791	$M
Acquisition Price	C	383	450	518	$M
Capacity Factor	A	82%	92%	97%	%
Capacity Factor	B	60%	70%	80%	%
Capacity Factor	C	50%	60%	70%	%
Heat Rate	B	5,800	6,150	6,600	BTU/kWh
Heat Rate	C	6,200	6,500	7,000	BTU/kWh
Fixed O&M	A	45	50	60	$/kW-yr
Fixed O&M	B	13	14.5	17	$/kW-yr
Fixed O&M	C	9	10	12	$/kW-yr
Tax Rate	All	35%	40%	42%	%
Debt Fraction	All	50%	60%	70%	%
O&M Escalation	All	2%	3%	4%	%/yr

Document prepared by SMU NAPE Case Team — February 18, 2026. All NPV and sensitivity figures derived from scenario_definitions.json, yearly_projections_scenario_{A,B,C}.csv, and forecast_results_target_6.json. This supplement is intended as an analytical reference and does not constitute investment advice.